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CALIFORNIA ENERGY FLOW IN 1994

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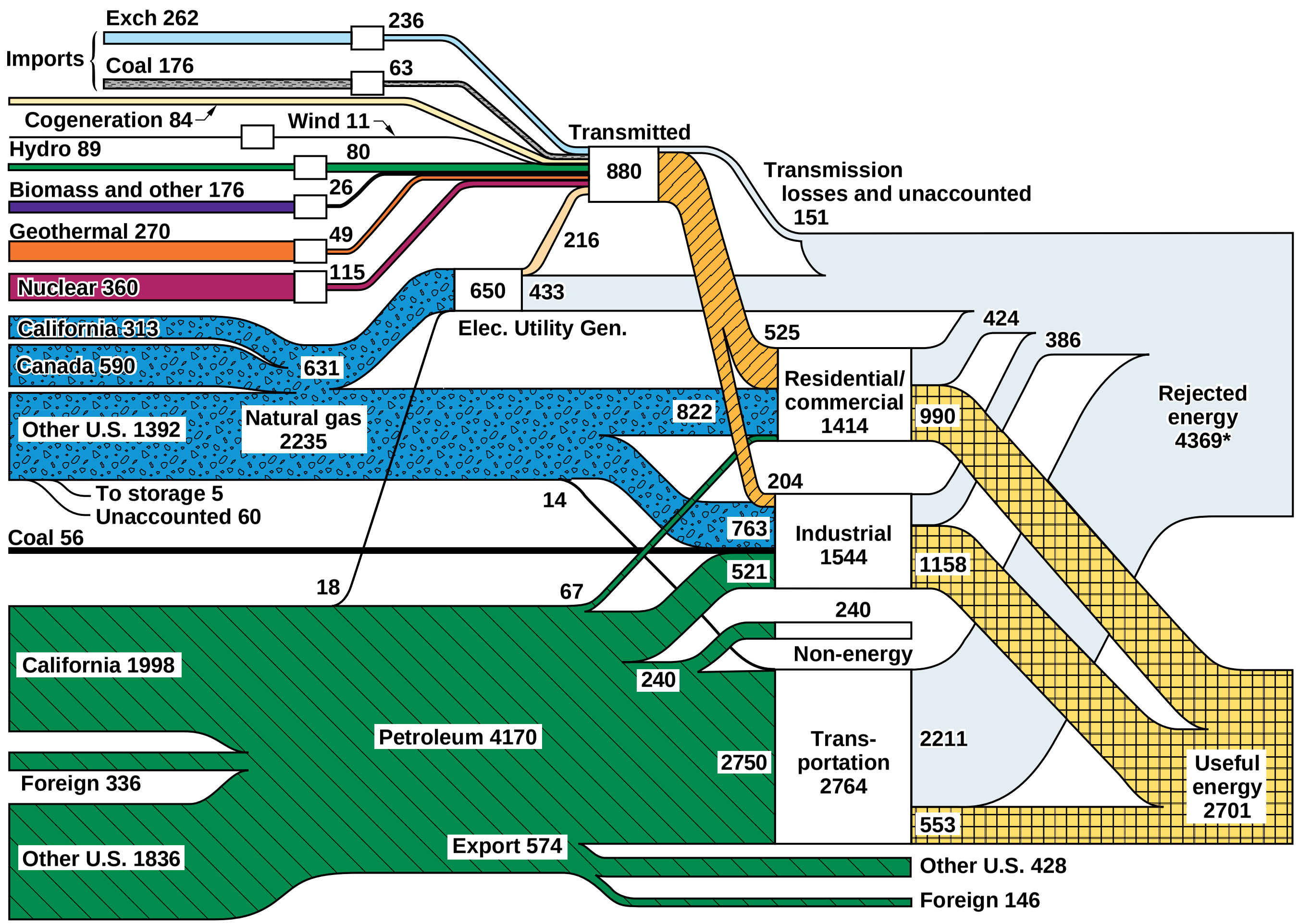
FIGURE 1. CALIFORNIA ENERGY FLOW -1994
TOTAL CONSUMPTION 7230 $\times 10^{12}$ Btu



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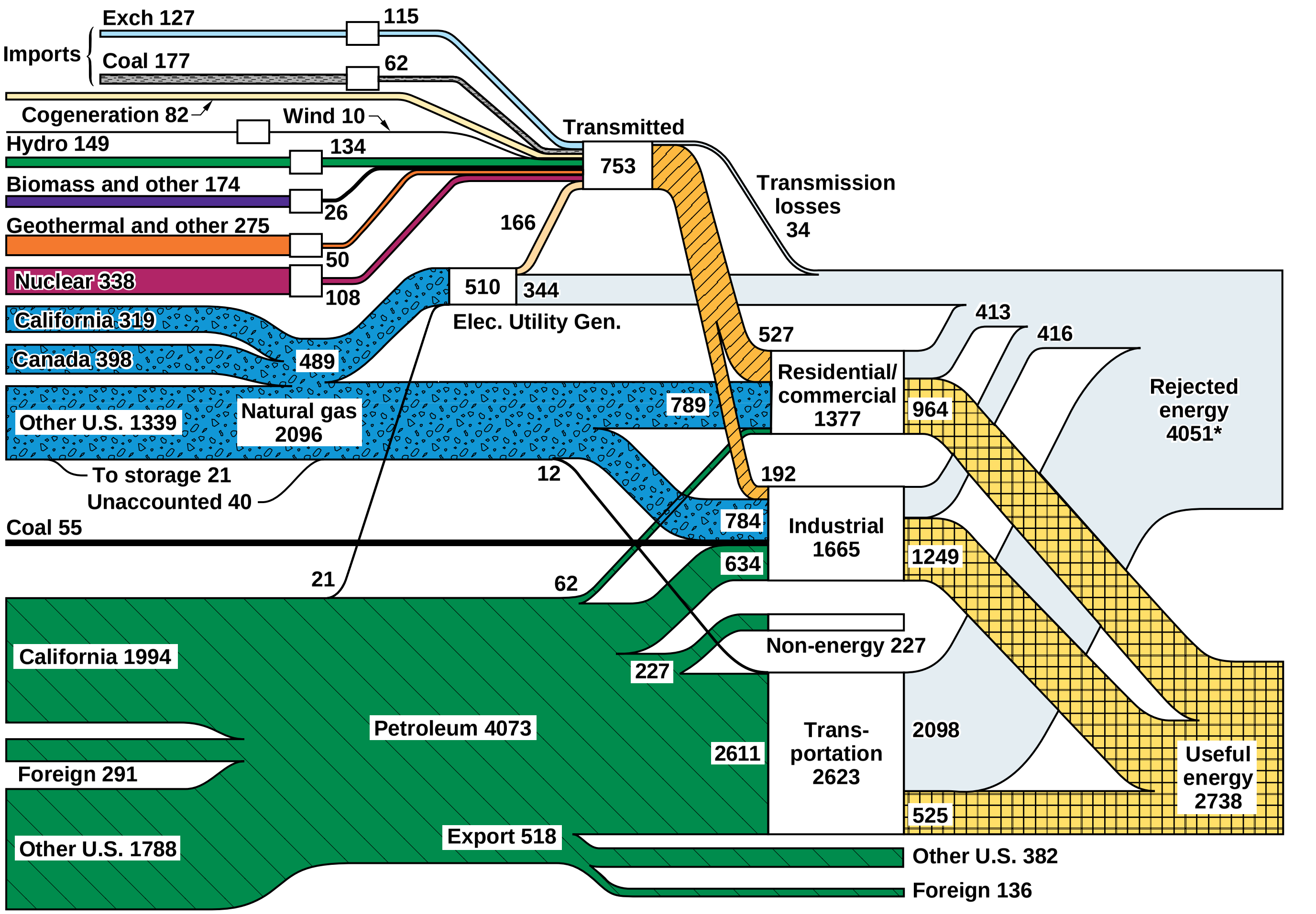
* Includes rejected energy for hydro, coal, geothermal, and nuclear conversions

FIGURE 2. CALIFORNIA ENERGY FLOW -1993
TOTAL CONSUMPTION 6800 × 10^{12} Btu



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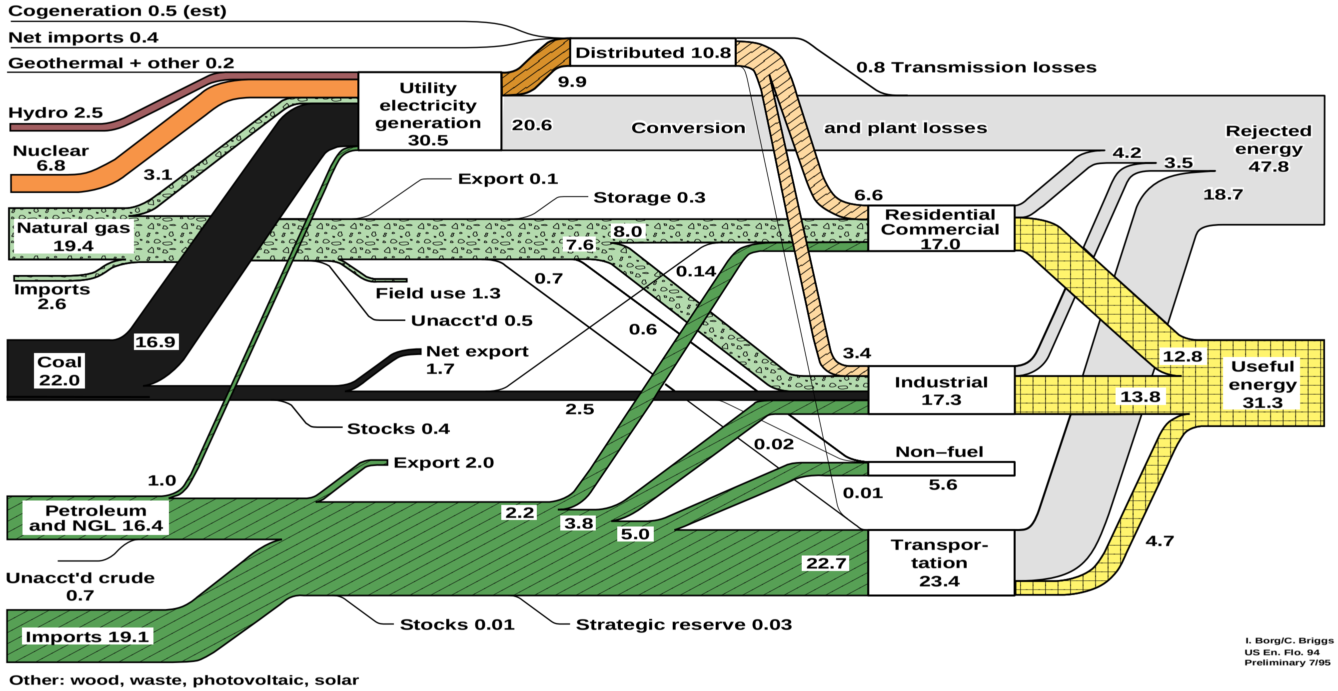
* Includes rejected energy for hydro, coal, geothermal, and nuclear conversions

FIGURE 3. U.S. Energy Flow – 1994
Net Primary Resource Consumption 85 Quads



energy balance between the two is given in Appendix C. Also shown on the right of Figures 1, 2, and 3 is the division between "useful" and "rejected" energy based on estimates of conversion efficiencies in the various end-use sectors. "Rejected energy" consists primarily of heat losses. Conversion and plant losses at electric utility generation stations that burn fossil fuels are a matter of record, but inputs to total transmitted electricity such as nuclear and geothermal power, are associated with *estimated* efficiencies of the conversion process to electricity. These estimates vary from 90% in the case of hydroelectric power to 18% for geothermal energy. In 1993 we revised our estimate of efficiency for the transportation sector down from 25 to 20% after a review of the subject.[2] The estimates of conversion efficiencies are given in Appendix D, and their rationales can be found in Ref. lb, 1c, and 2.

The box separating the energy source from the final electrical output represents the conversion process. In all cases the quantities associated with the energy source are calculated based on the assumed conversion efficiencies. While it is desirable to minimize the number of assumptions in preparing an energy flow diagram, it is also desirable to express as closely as possible the energy content of the sources used during the year. In this way it is possible to see at a glance which energy sectors are associated with the greatest conversion losses and are thus the largest targets for potential technological improvements in conversion efficiencies.

Power from cogenerators that is sold to utilities is shown in the figures as inputs to total transmitted electricity and appear without a box (representing the conversion process) that ordinarily would appear between the energy content of the fuel and the final product. In this instance, electric conversion losses are included in "rejected energy" from the industrial sector. Not shown in the flow diagrams is the amount of electricity used "in house" by the cogenerators and self-generators, but an estimate is given in the section on "Nonutility Generation." Thus the amount of electricity consumed by the industrial sector, 204×10^{12} Btu in Figure 1, represents purchases from the utilities *only*.

Starting in 1992 the energy flow diagrams shown in Figures 1 and 2 reflect losses associated with electric conversions by the small independent power producers. Their collective sales of electricity to the utilities have been part of the public record and included in the charts; however, heretofore the fuels or type of energy used to produce electricity have not been available in a timely manner. Hence it has not been possible to estimate conversion losses. Generally the small power producers utilize energy sources, such as biomass or geothermal, whose conversion efficiency to electricity is lower than the conventional fossil fuels used for power production. The efficiency of fossil-fueled electric utility boilers is approximately 33%, whereas the average efficiency of all biomass plants operated by nonutilities is approximately 12%,[3] and it is 18% for geothermal plants.

Electricity consumed by the residential/commercial end-use sectors shown in Figures 1 and 2 includes an “other” category of consumption tabulated by the U.S. Department of Energy. It includes street and highway lighting and other sales to public authorities, as well as sales to public railroads and railways. Lacking a breakdown in the “other,” it is not possible to indicate how much of this electricity properly belongs in the transportation sector.

CALIFORNIA’S ENERGY FLOW IN 1994 COMPARED TO 1993

The Economy

In 1994 California was in the midst of a solid recovery from a recession that ended in 1993.[4] Most economic indicators showed impressive, positive gains by year-end (Table 1). Nonetheless the unemployment in the state during 1994—8.6%—was high compared to the national average of 7.1%.[5] Among the 50 states, only West Virginia had a higher unemployment rate. The unemployment in the state reflects continued reductions in federal defense spending and a shrinking aerospace industry, which cut 40,000 jobs in 1994.

Table 1. Selected economic data for California—1994.[5]

Indicator	Percent change from 1993
Unemployment	-6.5
Housing units authorized	+14.4
New auto registrations	+3.7
Total taxable sales	+4.5
Personal income	+2.8
Consumer price index	+1.4

Another indicator of economic activity, the number of new construction projects started during 1994 (Table 2), similarly points to the end of recession in the state. Despite rising interest rates, the number of building sales and new construction permits rose. Commercial lending by the state’s major banks also increased after a three-year decline.

Table 2. Construction authorized by permit—1994.[5]
(Value in millions of dollars)

Year	Residential	Nonresidential	
		Commercial	Other*
1988	26,361	6,569	7,592
1989	27,790	6,159	7,507
1990	20,686	5,270	7,466
1991	15,056	3,374	6,247
1992	14,451	2,472	5,683
1993	12,932	2,137	5,420
1994	14,823	2,019	5,762

*Other consists of all other categories including additions and alterations of $100,000 or more.

Inflation in California, which traditionally exceeds the national average, lagged the U.S. average of 2.7% by more than a percent (Table 1). The California consumer price index is a weighted average of published indexes for the Los Angeles and San Francisco Bay areas.

Energy Consumption

In response to an improved economic situation and a cooler winter, total energy consumption increased by 6% in 1994. Comparison of components of California energy supply and demand for the past decade are given in Table 3. The weather indicators for principal metropolitan centers are given in Table 4.

The increase in energy demand was met by increased consumption of natural gas. This was made possible by the 1993 opening of two new major pipelines into the state that carry natural gas from Western Canada and from the Southwest.

The residential/commercial sector increased its gas use by 4%, reflecting greater space-heating requirements. An even larger increase in the use of natural gas was registered by the electric power industry. Electric demand as measured by the amount of transmitted electricity rose a hefty 17%. In view of the greater demand and the below-normal amount of hydropower available during the year, the utilities increased the amount of out-of-state imports and their gas-fired electrical generation. The amount of imported power and gas

Table 3. Comparison of Annual Energy Use in California (in 10^{12} Btu).

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Natural gas	1865	2034	1697	2091	1932	2087	2069	2089	2132	2096	2235
Crude oil (less exports)	3477	3580	3601	3591	3899	4015	3884	3731	3736	3555	3596
Utility electric sales	700	673	697	718	744	757	763	713	729	719	729
Residential/commercial	1176	1325	1224	1325	1350	1403	1474	1442	1394	1377	1414
Industrial	1493	1648	1456	1439	1557	1646	1560	1616	1711	1665	1544
Non-energy	221	185	203	292	235	237	252	245	250	227	240
Transportation	2464	2384	2499	2564	2715	2781	2817	2800	2707	2623	2764
Total energy consumption*	6200	6400	6200	6600	6750	6950	6900	6800	7200	6800	7200

* Total is not sum of the last four end-use categories because of rounding and inclusion of losses associated with conversion to electrical energy. Prior to 1992, losses associated with small power producers selling electricity to utilities were not included in Total Energy Consumption.

Table 4. Weather Comparison. 1968–1994 Annual Heating Degree Days*

	San Francisco Federal Office Building	Los Angeles Civic Center	San Diego Lindbergh Field
1968	2942	850	1052
1969	3066	1032	1145
1970	3006	941	1137
1971	3468	1424	1657
1972	3240	918	1166
1973	3161	1066	1137
1974	3182	1084	1123
1975	3313	1548	1416
1976	2665	1128	793
1977	2888	911	747
1978	2599	1208	736
1979	2545	1160	902
1980	2799	597	590
1981	2819	506	573
1982	3195	975	913
1983	2386	602	623
1984	2648**	704	713
1985	2486**	921	1079
1986	1842**	473	843
1987	2150**	979	1201
1988	2194**	867	1102
1989	2526**	844	1068
1990	2340**	839	1172
1991	2422**	879	1212
1992	1718**	705	866
1993	2071**	680	948
1994	2670**	733	1335
Normal			
1951-80	2750	1204	1284

1961-90***	3005	1154	1256

*A “degree day” is a term that describes the relationship of energy consumption to outdoor temperatures. “Heating or cooling degree days” are deviations of the mean daily temperature from 65°F. For example, for a day with a mean temperature of 40°F, the “heating degree days” would be 25 and the “cooling degree days” 0. Annual heating degree days are the sum for the year. Greater number of heating degree days means greater fuel requirements.

**CA. Mission Dolores - same historical data as for Federal Office Building

***Revised 1993.

Source: Local Climatological Data for San Francisco, Los Angeles and San Diego, National Oceanic and Atmospheric Admin., National Climatic Data, Asheville, NC.

burned rose 105% and 29% respectively. The amount of cogenerated electricity sold to the utilities increased slightly and remained an important source of power for the utilities.

Industrial and related non-energy uses decreased 5% in 1994. “Non-energy” is a designation for products produced from fossil fuels—such as petrochemicals, fertilizers, waxes, lubrication oils, and asphalt,—that are not burned to produce energy. Asphalt, a by-product of the state’s petroleum refining industry, is the principal constituent of the “non-energy” category in California.

Demand for transportation fuels, the *bête noire* of conservationists in California, increased a modest few percent. A breakdown of the consumption of transportation fuels 1988-1994 is given in the “Transportation Fuels” section that follows. Sales of gasoline actually fell, but increased use of diesel and aviation fuels more than compensated for the decline. Increased sales of bunkering fuels contributed to the overall increase in demand for transportation fuels as a group.

TRANSPORTATION FUELS

Consumption

For the 20th consecutive year, travel on the California state highway system was up (1.26%).[6] In keeping with the increase in travel, sales of taxable gasoline and diesel fuels and registrations of new automobiles and commercial vehicles also increased. Noteworthy was the relatively large increase (6.9%) in the number of new commercial vehicle registrations, reflecting the growing popularity of trucks, vans, recreational and off-road vehicles as well as improvement of the economic health of the state’s businesses in 1994.

Bus ridership as reported by the 11 major operators within metropolitan areas fell for the third year in a row.[6] Intercity bus travel fell by almost 14%. Riders on ferries and intercity and commuter rail systems in the state also decreased. Although there were a few rail systems that had an increased number of passengers—e.g., Caltrain on the San Francisco Peninsula and Sacramento’s Metro—the loss in 1994 of one million passengers on the Bay Area Rapid Transit system, the largest system in the state, more than compensated for the increases.

Air traffic, both private and commercial, showed a substantial increase that was reflected in increased sales of aviation gasoline and jet fuels.

The sale of bunkering fuels at California ports showed a marked increase (Table 5) but did not reach pre-1991 levels. The decline beginning in 1991 reflected the imposition of new state taxes that sent the shipping trade to other West Coast ports for fuels.

Table 5. California transportation end-use (in 10^{12} Btu).

	1988	1989	1990	1991	1992	1993	1994
Net gasoline*	1612	1630	1664	1712	1670	1681	1626
Net aviation fuel	427	458	475	476	510	520	565
Taxable diesel fuel – public highways	244	265	253	246	256	253	275
Rail diesel	26	30	31	33	30	27	29
Net bunkering fuel	357	348	344	288	202	193	237
Military	29	30	29	26	23	7	18
Natural gas-pipeline fuel	20	20	21	19	16	12	13
Natural gas vehicular	-	-	0.004	0.01	0.03	0.27	0.58
Total**	2715	2781	2817	2800	2707	2693	2764

* As of January 1, 1992, leaded gas was no longer produced at California refineries.

** Some electricity is used for mass transit; however, the amount is not monitored on a statewide basis and hence does not appear in this table or in Figures 1 and 2.

Source: *Fuel and Kerosene Sales-1994,* DOE/EIA-0535(94), U.S. Department of Energy, Washington, DC (September 1994); *Quarterly Oil Report, Annual Issue 1994* (Net gasoline and aviation fuel), California Energy Commission, Sacramento, CA (May 1996); *Natural Gas Annual-1994,* DOE/EIA-0131(93) Table 52, U.S. Department of Energy, Washington, DC (November 1995).

Alternative Fueled Vehicles

For 15 years the California Energy Commission (CEC) has actively supported the development of alternative fuel vehicles (AFV) by conducting demonstrations and addressing issues that represent barriers to greater U.S. use of alternative fuels. Alternative fueled vehicles play a minor role in the state's transportation system. Table 6 summarizes the CEC's estimate of the size of the California AFV fleet in 1994.[7]

According to a CEC staff report, the largest impediment to increased market penetration of AFVs is lack of infrastructure to fuel (or recharge), service, and support such vehicles.

Table 6. California alternative fueled vehicle fleet, 1994.[7]

Fuel	Vehicles in use	Cents per mile*

Methanol	6500	3.4
Compressed natural gas	508	2.8
Liquid petroleum gas	56,000	3.5
Electricity	2,877	2.4

* Cost/mile is based on the gasoline equivalent price. Cost/mile for gasoline is 2.7 cents per mile in 1994. Cost/mile for electricity is based on off-peak power cost.

Vehicle Emission Standards

In May 1994, the California Air Resource Board (CARB) upheld its 1990 ruling that by 1998 two percent of the vehicles sold in the state will emit zero pollutants. In the interim, Massachusetts and New York have adopted, and nine other states are considering adopting, similar rules. In California, the required number to be sold escalates to 5% in 2001 and 10% in 2003. Because 1,294,300 new automobiles were sold in California in 1994,[7] the 2% rule is tantamount to the sale of 30,000 to 40,000 electric or battery-operated vehicles. Although the auto industry has lobbied vigorously against the rule for five years, most were preparing to launch a lead-acid battery car in California in 1998. The principal argument advanced by the industry is that the battery technology is not sufficiently advanced to provide the driving range or comforts, such as heating and air conditioning, that customers demand at a price they can afford. They also argue that the additional electricity needed to operate the vehicles in the end will require the burning of additional fossil fuels, thereby causing additional pollution. In California the argument is not persuasive because electrical production in the state does not rely on the principal polluting fossil fuels (coal and oil) (Figure 1), and additional electrical demand in the past has been met by imports from neighboring states. Further, the CARB rule was formulated specifically to lower smog in populated areas where the chief source of pollution is vehicle exhaust containing hydrocarbons, NO_x and CO.

On another front, state refineries were struggling to meet CARB and federal deadlines for the production of reformulated gasoline for sale in nonattainment areas, such as the Los Angeles basin. Production of reformulated gasoline requires boosting oxygen; lowering vapor pressure; reducing benzene, olefins, aromatics and sulfur; and adjusting distillation temperatures. The design is to reduce volatile organic compounds, NO_x, and air toxics. The capital cost of refinery modifications collectively exceed $1 billion.[8] The federal Phase I reformulated gasoline specifications are provisions of the 1990 Clean Air Act amendments to come into play January 1, 1995. Phase II of the CARB specifications go into effect March 1, 1996. The CARB requirements in both Phase I and II are generally tougher than their federal counterparts. By the time the federal program peaks in 2000, California will have been subject to more stringent requirements for four years. CARB's Phase II regulations exceed those in Phase II of the federal program. Because not all gasoline produced in California stays in the state, even in Southern California not all refineries have opted to produce the modified fuel.

OIL AND NATURAL GAS PRODUCTION

Oil Production

California is the fourth largest oil producer in the nation, behind Texas, Alaska, and Louisiana. As expected, onshore production continued to decline in 1994, and the combined onshore and offshore production was 81% of the record high reached in 1985. The largest declines were registered in the state's largest fields, Midwest-Sunset and South Belridge in Kern County. Both of these heavy oil fields depend heavily on steam injection for production.[9] Collectively 652 wells were plugged and abandoned in the two fields.

Production at the Elk Hills field, which was designated Naval Petroleum Reserve No. 1 to ensure a supply of oil for the U.S. Navy by President Taft in 1912, was slightly up from 1993. It is the fifth largest producing oil field in the state; 78% of the field is owned by the federal government, with the remainder owned and operated by Chevron U.S.A. Production Co. That share is administered by the U.S. Department of Energy and managed and operated under a contract with Bechtel Petroleum Operations. During the year, the 42.5-MW Elk Hills Cogeneration Facility began operating, bringing the district's cogeneration capacity to 1.64 GW.[9] The steam-producing cogeneration facilities are fueled by natural gas that is brought in by pipeline from out-of-state sources. Surplus electricity is sold to a public utility.

One continuing bright note in the California oil production picture has been increased output from federal offshore fields that lie 3 to 200 miles from the coast. Two standouts were the Point Arguello and the Pescado field in the Santa Ynez Unit west of Santa Barbara. Increase in production in these two fields more than compensated for the drop in production from onshore and state offshore fields. In 1994 Chevron, which owns and operates the Point Arguello offshore field, lost its interim tankering permit, which was contingent on finalizing an agreement with an onshore pipeline to carry the field's crude oil.[10] The permit allowed Chevron to tanker its crude directly to Los Angeles refineries rather than piping it in existing pipelines to northern California and Texas refineries, which have limited capacity to utilize heavy oils. Adding to the transportation bottleneck for offshore oil was the January 1994 Northridge earthquake, which shut down the Four Corners No. 1 pipeline to Los Angeles, and the increased production from Exxon's Pescado field. In view of the fact that plans for a 130,000-barrel/day pipeline from central California to Los Angeles refineries (Pacific Pipeline System, Inc.) were moving ahead, Chevron applied again for an interim tanker permit, contending that the conditions of the original interim tanker permit had been met. The Pacific Pipeline System Inc. is owned by Chevron Corp., Texaco Inc., Unocal Corp., and Anschutz Co.

In September 1994, Governor Wilson signed a bill to permanently ban oil drilling in state waters along California's coastline. It contained an exemption for a Mobil project involving slant drilling from onshore.[11] The bill was authored by a Santa Barbara Assemblyman, who reflected his county's long-standing objection to offshore oil and gas production off its coast. The bill was opposed in principle by the oil industry; however, the industry has shown little interest in drilling offshore in recent years and has relinquished the largest share of leases obtained from early Federal OCS sales without drilling them. A ban was placed on the sale of leases in federal waters off California by President George Bush in 1992.

Natural Gas Production

About 15% of California's gas supply comes from production within the state. About two thirds of the total consists of natural gas produced in association with oil production, and the remainder is so-called "nonassociated" gas. The latter comes principally from gas wells in the Sacramento River delta area. Production of "associated" gas is also largely from onshore fields. Both associated and nonassociated gas production peaked in 1985,[9] at which time their contribution to the total California production was approximately the same. In the intervening years production from both sources has declined, and by 1994 combined production was 63% of 1985 production. The largest declines have been registered in nonassociated gas. The total amount of gas produced in connection with oil production has been bolstered by production in the federal offshore areas, where new discoveries have come on line.

OIL AND NATURAL GAS SUPPLY

Oil Supply

The source of oil supplies changed little from 1993. Slightly more than half of the state's petroleum supply was imported; the remainder was from state onshore (77%), state offshore (6%), and federal offshore (17%) production. Of the imported oil, the bulk consisted of North Slope, Alaska, crude oil that was tankered from Valdez, Alaska. Foreign imports, which made up 8% of total supply and about 15% of total imports to the state, came primarily from Canada and Indonesia.

Natural Gas Supply

The steady decline in California natural gas production, fuel switching driven by California's stringent air pollution regulations, and the general growth of gas use in residential and commercial sectors have required large increases in out-of-state imports to meet California demand. Gas production is about half of its historic highs set between 1966-8. The offsetting imports have grown so that they comprised 88% of total supply in 1994, with 62% from the Southwest U. S. and 26% from Canada (Figure 1).

Pipeline construction in California slowed in 1994 after a period of rapid growth in pipeline capacity. The two biggest projects completed in 1993 were (1) the Kern River pipeline, a direct link to Rocky Mountain gas reserves, which provide gas for the enhanced oil recovery operations and cogeneration in Southern California, and (2) additional capacity on Pacific Transmission Company's 805-mile pipeline from Canada. Pacific Transmission Company is a wholly owned subsidiary of Pacific Gas and Electric Co. (PG&E), the utility that services Northern California. Because the Canadian pipeline was opened at the end of 1993, its effect was not felt until 1994, when imports from Canada jumped 48%. Exploration and development in Canada's gas provinces have surged since 1992, and Canada's markets are expected to grow such that it will be a significant supplier in future years.[12]

ELECTRICAL POWER

Source of Supply

Electricity distributed by California utilities derives from numerous sources: imports from out-of-state generators (principally from the southwest U.S.); utility generators utilizing fossil fuels, hydropower, geothermal energy, and nuclear reactors; and purchases from nonutility generators using a variety of fuels (Table 7). Utility generating capacity by fuel source is given in Table 8.[13]

Nuclear Power

California utilities operate two nuclear plants within the state and have a 15.5% interest in the Palo Verde plant at Phoenix, AZ. Each of the two in-state nuclear installations consists of two ~1000-MW nuclear reactors, and collectively they produce

Table 7. Sources of California Utilities' Distributed Electricity - 1994.

Source		Net electrical energy (trillion Btu)
Imports		172
Out-of-state coal and nuclear facilities:	66	
Purchases:	106	
Fossil fuels		166
Natural gas:	159	
Oil:	7	
Nuclear power (in-state)		108
Hydropower		135
Geothermal power		54
Windpower		12
Cogeneration		96
Biomass, solar, and coal		31
TOTAL		774

Table 8. California utility (in-state) electrical generating capacity.[13]

Primary energy source	Capacity* (GWe)
Petroleum	2.11
Gas	21.96
Water	13.25
Nuclear	4.31
Other (principally geothermal)	1.67
TOTAL	43.30

* Summer capability as of December 31, 1994.

about 10% of the electricity generated within the state. The total contribution increased again in 1994. Both the Diablo Canyon nuclear plant in San Luis Obispo County and the San Onofre Nuclear Generating Station in San Diego County were built with large cost overruns. In the case of Diablo Canyon, the California Public Utilities Commission (CPUC) declined to allow the cost overruns to be passed onto consumers and instead in 1988 negotiated a novel rate settlement with the utility-owner (PG&E) that tied the return on investment to performance and electrical output rather than the usual cost basis. Better-than-expected performance at Diablo Canyon has led to a steady escalation in the price per kWh received in keeping with the terms of the settlement. In 1994 it was 11.89 cents. In January 1995, attorneys representing consumer groups filed a motion with the CPUC to reduce the price of power at Diablo Canyon to 11.00 cents per kWh from the increase to 12.15 cents per kWh scheduled for 1995 according to the settlement formula.[14] These high rates are a contributing factor in making the utility's charges to customers among the highest in the nation. The proposed decrease reflects the view that the 1988 rate settlement had resulted in an unreasonably high rate of return. The excellent performance history at Diablo Canyon was unanticipated. It relates to the newness of the installation and to the concerted effort on the part of the utility to improve performance. The latter was accomplished in large part by reducing the time required to refuel the reactors. Refueling time has fallen substantially over the history of the plants—from an average of 64 days in 1989 for the two units to 45 days in 1994. Each unit produces about $3 million of revenues per day at full power operation, and a 1% increase in the combined annual capacity factor for the two units increases revenues by approximately $21 million based upon 11 cents/kWh.[15] Because both units were refueled in 1994, the combined capacity factor was down as compared to the previous year when only one was refueled.

Both Southern California Edison Co. (SCE) and San Diego Gas and Electric Co. (SDG&E),[15] who jointly own the San Onofre Nuclear Generating Station, requested permission from the CPUC to put in place a performance-based plan to recover costs to replace the existing, traditional cost-basis method. Both wish to recover their costs at a faster rate in order to be in a better position to enter the competitive electrical market that is on the horizon. The CPUC ruled favorably in the case of both proposals.[16]

Hydropower

The modest contribution of in-state hydropower to the state's supply (shown in Figure 1) belies the important role water-generated electricity plays in California. The bulk of the imports coming into the state from the Pacific Northwest and the Southwest are from the hydroelectric resources of the Bonneville Power Administration and the Western Area Power Administration respectively. The latter administers the federally owned Glen Canyon and Hoover Dams.

The amount of hydroelectricity generated within the state declined in 1994 (Figure 1 and 2) because of a large decline in the 1993-1994 rainfall (July 1 to June 30) following the very wet

1992-1993 season. A return to the drought conditions that prevailed earlier was not suggested because rains in late 1994 indicated a return to normalcy.

Nonutility Generation

The important role that nonutility generation plays in the electrical supply of the state (Table 9) has been influential in the decision of the CPUC to press for deregulation of the state's utilities. In California, nonutility generators consist of cogenerators whose fuel of choice is overwhelmingly natural gas.[17] The next largest contributions to nonutility supply are made by wind generators and geothermal operators. Nonutility suppliers have traditionally sold their electricity to the publicly owned utilities at regulated rates and have never had the opportunity to compete for customers.

California's nonutility generators lead the nation in sales to the public utilities. Although the gross output of Texas' nonutility generators approaches that of California, less than half of the power produced flows into the state's electrical grid. In contrast to the California situation (Table 9), in Texas the bulk of the electricity is used by the power producing facilities themselves.

Table 9. Production of electricity by California utilities and nonutilities.[17] (billion kWh)

	Year 1992	1993	1994
Net generation by public utilities	119.3	125.8	126.7
Gross* generation by nonutilities	67.0	62.8	63.2
Receipts (purchases, exchanges, etc.)	4.4	3.0	3.4
Deliveries to utilities	50.5	53.4	53.1
Facility use	13.1	12.4	13.4

*Note: The gross-to-net generation conversion factor varies from 0.99 to 0.97 depending on the type of prime mover.[17]

Alternative Sources of Electricity

Geothermal

Geothermal energy is often included in discussions of renewable forms of energy, and it comes as a surprise to many that it is subject to depletion similar to that associated with oil and gas reserves. For the past several years evidence of depletion has been apparent in the steam production at The Geysers near Calistoga, CA, the world's largest geothermal field. Reinjection of condensed vapor after it has been used to power electricity-generating steam turbines has been ongoing at the field for decades; however, it has only slowed but not reversed the steady decline in steam production at the field. The gross amount of steam produced in 1994 (Table 10) is 70% of the historical high set in 1987. Twenty-three wells were formally abandoned in 1994.

Table 10. Principal geothermal installations in California (1994). [9]

Field	Gross installed capacity (MWe)			Steam/fluid production (billions of kilograms)		
	1992	**1993**	**1994**	**1992**	**1993**	**1994**
Coso Hot Springs	260	260	260	41.2	47.7	43.3
East Mesa	130	125	110	97.6	97.8	90.6
The Geysers	1900	1900	1900	88.5	84.4	78.4
Heber	52	85	90	29.5	41.7	53.9
Mono-Long Valley	40	40	40	24.6	23.5	23.6
Salton Sea	240	240	240	78.0	77.8	77.8
Wendell-Amedee	3	3	3	8.5	7.9	7.3
Total	2625	2653	2643			

Approximately one-third of the condensed vapor at The Geysers is reinjected; the remainder is lost to the atmosphere.[9] In an effort to increase the amount of injected fluid, a joint project between the city of Clearlake and the operators at the field was given the go-ahead in 1994. The plan is to build a pipeline to carry treated waste water from Clearlake to the field, where it will be injected to increase steam production.

The state's other geothermal fields produce hot water or brine as opposed to vapor and thus require more complex technologies to convert the energy to electricity. Starting in 1994, zinc was a by-product of operations at the J. J. Elmore plant in the Salton Sea field. The almost pure metal is extracted from the brines by ion-exchange methods before it is reinjected into the ground. In general, recovery of the fluids is more complete in water-dominated geothermal fields, and hence larger percents of the amounts produced are reinjected. Nonetheless water-dominated systems are also subject to depletion, as evidenced by the retirement of a 13.4-MW (gross) binary plant in the East Mesa geothermal field in 1994. One bright spot was increased production in the Heber field in Southern California (Table 10), where the number of producing wells has more than doubled between 1992 and 1994.

Solar Electricity

The amount of energy captured by solar thermal collectors goes largely unmonitored in the United States. Some estimates are possible from the number of collectors shipped from manufacturers since 1974. Assuming a 50% overall efficiency and exposure to 1,500 Btu insolation per square foot per day, the solar contribution has been calculated at 0.06 quads (quadrillion Btu) for 1994.[18] Reference to Figures 1, 2, and 3 can put this number into perspective.

Although it is not possible to know California's contribution to this total, it is probably large judging by the state's share of the number of solar photovoltaic installations in the United States. Combined utility and nonutility installed capacity of solar electric units in California is 362-MW, which represents more than 95% of the total installed in the United States.[18] Gross electrical generation in 1994 from solar modules in California is estimated at 811 million kWh,[18] almost all of which was from nonutility power producers.

Windpower

California remains the largest producer of windpower in the world, although its share has fallen below 50% of grid-connected capacity from a high estimated at 70%. The decline in California's share is due primarily to increased utilization in other parts of the world. According to the California Energy Commission, during 1994 both the amount of electricity generated (3.27 billion kWh) and total installed capacity in the state were at 1993 levels. The number of turbines in operation declined because of the retirement of older, less efficient wind turbines. Because some were replaced by newer models, the result was an overall increase in the statewide capacity factor, which reached 23%, as compared to 30% that is estimated to be possible. (Capacity factor is the ratio of actual energy output to the possible output if operated 24 hours a day at full rated power).

The two largest concentrations of wind turbines in California are near the Altamont Pass in Northern California and the Tehachapi Pass area in Kern County in Southern California (Table 11).[19] The production of power in the Altamont Pass area is more affected by seasonal winds than the Tehachapi area; however, both areas register uneven monthly output. Statewide, approximately 73% of wind-generated electricity is produced between April 1 and September 30 when the rising hot air in the inland valleys is replaced by eastward-moving, cooler coastal air. The match with high electrical demand during the summer months is good but not perfect.

Table 11. Windpower installations in California as of January 1.[19]

Location	Capacity (MW_e)				Number of turbines			
	1992	1993	1994	1995	1992	1993	1994	1995

Altamont Pass area, 45 miles east of San Francisco	704	683	638	625	6818	6451	5952	5901
San Gorgonio Pass, Riverside County near Palm Springs	255	263	267	274	3581	3646	3683	3092
Tehachapi Pass, Kern County	644	632	627	630	5221	4992	4908	4801
Carquinez Strait, Solano County	60	60	60	65	600	600	600	617
Pacheco Pass, San Benito County	16	16	16	16	167	167	167	166
TOTAL	1679	1654	1608	1610	16,387	15,856	15,310	14,577
Capacity factor*	20	19	20	23				

*Capacity factor is defined as the ratio of actual energy output to the amount of energy a project would produce if it operated at full rated power for 24 hours per day within a given time period.

Pollution-free windpower has always been a favorite with environmentally conscious Californians. All through the 1980s the industry enjoyed generous tax credits and mandated purchase contracts with the regulated utilities, which guaranteed high prices for the power, up to 14 cents per kilowatt hour. The then-infant industry thrived; however, many of the lucrative contracts with the utilities have lapsed, and the new standard contracts are designed less to be subsidies than to be competitive with other types of electrical generation. Nonetheless, in 1993 the CPUC ordered the state's investor-owned utilities to hold auctions for the purchase of 1400 MW of power from independent generators.[20] Among the winners were several windpower firms. The three public utilities protested the auction on several grounds; they argued that they were being forced to buy capacity above their "avoided costs,"* and secondly, that several have excess generating capacity of their own. One utility actually pays some of its current wind producers under contract not to deliver their power.[21] Their principal complaint with windpower is that its time of arrival is not necessarily coincident with demand. In March 1995, the Federal Energy Regulatory Commission ruled that the auction was illegal because the CPUC had not correctly calculated the utilities' avoided costs, and further that it was in conflict with its own proposal on restructuring and deregulating the utilities.[22] The ruling promises to have long-reaching consequences to all of the electrical generating facilities that qualify to receive benefits under the Public Utility Regulatory Policies Act.

Despite the U.S. Department of Energy's forecast that the nation's windpower will increase about 10% per year between 1994 and 2015,[23] there were indications of problems within the industry at the end of 1994. Kenetech, the second largest operator, posted substantial losses and laid off some of its employees, resulting in a dramatic fall in the price of its stock.[24] It is questionable whether the company could have met the terms of its contracts with the state's three utilities that it had won at the "illegal" auction held in late 1993.

Deregulation of the California Electric Power Industry

Restructuring of the electrical power industry was made possible by two federal acts, The Public Utility Regulatory Policies Act of 1978 and the Energy Policy Act of 1992. The first encouraged independent power production by requiring the public, investor-owned, utilities to purchase nonutility-generated electricity, and the second required the public utilities to transmit electricity generated by independent power producers. Collectively these acts were designed to give independent power producers access to retail customers and to allow customers to choose among suppliers. However, as long as rates charged by the public utilities were regulated by the CPUC, traditional suppliers potentially could find themselves in a noncompetitive situation. Hence California was one of the first states to move toward deregulation of the industry. After two years of study, in April 1994 the CPUC issued its proposal on how to restructure the electric services industry and solicited comment in a series of hearings that began several months later.[25] The proposal was designed to enable the utilities to meet the impending competition, reduce administrative costs of regulation, and lower the cost of service, which is on average the highest in the nation. The "blueprint" proposed that beginning January 1, 1996, consumers who receive service of over 50 kilovolts have direct access to electricity from power providers. Within six years all electric consumers would be given the choice of providers, including residential users. In those areas where competition does not exist, traditional regulation would be replaced with performance-based ratemaking.

The hearings in June 1994 brought out the complexities of the proposed deregulation. The three major public utilities in the state were concerned about (1) recouping their capital investment in existing facilities associated with erosion of their traditional market and (2) who would bear the transition costs, which are expected to be large. The environmental groups were concerned about the future funding of utility-sponsored programs designed to reduce consumption and to promote energy conservation. These programs have been financed by rate increases authorized by the

*"Avoided costs," are costs a utility would have to incur to provide additional electrical capacity.

CPUC. The nonutility generators, who have sold their power to the utilities under mandate from the CPUC at rates that sometimes exceeded the cost of utility-generated power, were concerned with their survival in a competitive market.

The most troublesome issues had to do with the specifics of how to manage the electric supply. Here the three major utilities differed; Southern California Edison Co. (SCE) and San Diego Gas and Electric Co. (SDG&E) recommended establishment of a wholesale power pool to provide back-up service to all users, and Pacific Gas and Electric Co. (PG&E) advocated free markets and bilateral contracts between providers and customers. Ultimately the CPUC commissioners approved the power pool; however, by 1995 the decision was being reconsidered and several hybrid plans were gaining acceptance.[26] Not waiting for the decision, in December 1994 PG&E announced a first-of-its-kind transmission agreement allowing a large, out-of-state, independent power producer to sell wholesale electricity throughout PG&E's service area.[27]

Yet to be resolved was the role to be played by the Federal Energy Regulatory Commission, which has jurisdiction over interstate power transactions. Because it is almost certain that out-of-state power producers will enter the California market, federal and state regulations will have to be brought into conformance. It was noted in the June 1994 hearings that the CPUC plan necessitates amending the Public Utility Regulatory Policies Act, which contains provisions dealing with mandatory power purchases on the part of the utilities as well.[28]

Although the proposal to be submitted to the California Legislature and the Governor for approval was far from finalized in 1994, the major public utilities individually began to take steps to improve their position to meet a future competitive market. Cutting costs was chief amongst the steps, but they made numerous proposals to the CPUC regarding rates.

SCE and SDG&E, co-owners of the San Onofre nuclear plant, in separate decisions were allowed to speed up the recovery of costs related to the station. SDG&E proposed using a new performance-based system.[29] PG&E proposed to reduce its rates that are associated with the Diablo Canyon nuclear plant over the next five years. The request was unusual because the utility had an agreement with the CPUC whereby it could *increase* rates over the next five years.[30] On another tack to meet future competition, PG&E continued to buy independent power plants. The purchases have been negotiated by U.S. Generating Co., a partnership consisting of PG&E Enterprises, a nonutility unit of the company, and Bechtel Enterprises, an arm of the giant construction company. Acquisitions in 1994 resulted in U.S. Generating Co.'s moving from fourth to third place nationwide in the ranks of independent power producers.[31]

APPENDIX A

Data Sources for California Energy Supply (1994)

Production	Source
Crude oil including federal offshore and lease condensate	Ref. 9.
Associated and nonassociated natural gas (marketed, dry)	Ref. 12, Table 52, Summary Statistics Natural Gas -California.
Electric utility fuel data	Ref. 17, Table 18, Consumption Petroleum & Gas to Produce Electricity.
Electrical generation	
Utility—oil, gas, hydro, nuclear,	Ref. 17, Table 13, Net Generation Electric Utilities by energy source.
Wind	Andrea Gough, California Energy Commission, personal communication, November 16, 1995.
Cogeneration and various small, nonutility power producers	Andrea Gough, California Energy Commission, personal communication, November 16, 1995.
Imports	
Natural Gas	
Foreign	Ref. 12, Table 9.
Domestic	Ref. 12, Table 52.
Crude oil Foreign and domestic	Ref. 32, Table 5, 5-1, 5-2, 5-3, 5-4, California Petroleum Summary.
Oil products Foreign and domestic	Ref. 32, Table 7, California Fuels Market Petroleum Activity.
Coal	Ref. 33, Table 46, Coal Consumption by Census Division and State.
Electrical power	
Net exchange	Andrea Gough, California Energy Commission, personal communication, November 16, 1995.
Coal	Ibid.
Exports	
Oil products	
Foreign and domestic (not including bunkering fuel supplied at California ports)	Ref. 32, Table 7.

APPENDIX B

Data Sources for California End Uses (1994)

Net Storage	
Natural gas	Ref. 12, Table 52.
Unaccounted for Natural Gas	Ref. 12, Table 52.
Transportation	
Crude oil	
Gasoline, aviation and jet fuels	Ref. 34.
Taxable diesel fuel (for public highways)	Ref. 35, Table 4, Sales for Transportation Use: Distillate Fuel Oil End Use, 1994.
Vessel bunkering (includes international bunkering)	Ref. 35, Table 4 and 5.
Rail diesel	Ref. 35, Table 4.
Military use	Ibid.
Natural gas	
Pipeline fuel	Ref. 12, Table 52,
Industrial, Government, Agriculture, etc.	
Natural gas (includes lease and plant fuel)	Ref. 12, Table 52.
Coal	Ref. 33, Table 46.
Electricity	Ref. 17, Table 4.
Crude oil	By difference.
Non Energy Applications	
Crude oil and LPG	
Asphalt	Ref. 36.
Petrochemical feedstock	Ref. 37, Table 41 (estimate) & Ref. 38, Table 12.
Waxes, lubricating oils, medicinal uses, cleaning	Ref. 32.
Residential and Small Commercial	
Natural gas	Ref. 12, Table 52.
Crude oil and other oils (kerosene, residual, and distillate)	Ref. 35, Table 6, Sales of Kerosene by End Use; Table 5, Sales of Residual Fuel Oil by End Use; Table 4, Sales of Distillate Fuel Oil by End Use.
LPG	Ref. 37, Tables 41-45 and Ref. 38, Table 12.
Miscellaneous. “Off highway” Diesel	Ref. 35, Table 4.
Electricity	Ref. 17, Table 26.

APPENDIX C

Energy Balance for 1994 (Figure 1)

SUPPLY			(10^{12} Btu)
Electrical imports			438
Wind			11
Hydropower			89
Cogenerated electricity			-[a]
Geothermal			270
Biomass, solar, coal, etc.			176
Nuclear			360
Natural gas			2235
Less net additions to storage			-5
Coal 56			
Petroleum			4170
Less exports			-574
Total			7226

DISPOSITION			
Useful energy			2701
Residential/commercial		990	
Industrial		1158	
Transportation		553	
Non-energy uses			240
Rejected energy			4369
Residential/commercial		424	
Industrial		386	
Transportation		2211	
CA electric generation		1058	
Fossil fuels[b]	433		
Nuclear[b]	245		
Hydropower[c]	9		
Geothermal[c]	221		
Biomass et al.[d]	150		
Out-of-state elec. generation, transmission losses and unaccounted		290	
Cogeneration (included in industrial)			-84
Total			7226

[a]Fuels included with petroleum and natural gas amounts.
[b]Utility generation.
[c]Combined utility and nonutility generation.
[d]Nonutility generation only.

APPENDIX D

Conversion Units and Assumed Conversion Efficiencies

Energy Source	Conversion factor, 10^6 Btu
Electricity	3.415 per million Wh
Coal	22.6 per short ton
Natural gas	1.05 per Mcf
Crude oil	5.80 per barrel
Fuel oil	
Residual	6.287 per barrel
Distillate, including diesel	5.825 per barrel
Gasoline and aviation gasoline	5.253 per barrel
Kerosene and kerosene-type jet fuel	5.67 per barrel
Asphalt	6.636 per barrel
Road oil	6.636 per barrel
Synthetic rubber and miscellaneous LPG products	4.01 per barrel

Assumed Conversion Efficiencies of Primary Energy Supply

Electric power generation	
Hydropower	90%
Coal	30%
Geothermal	18%
Oil and gas	33%
Uranium	32%
Biomass	12%
Transportation use	20%
Residential/commercial use	70%
Industrial use	75%

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